2. Impacts on Electricity Generation and Key Fuel Markets

Reference Case Trends

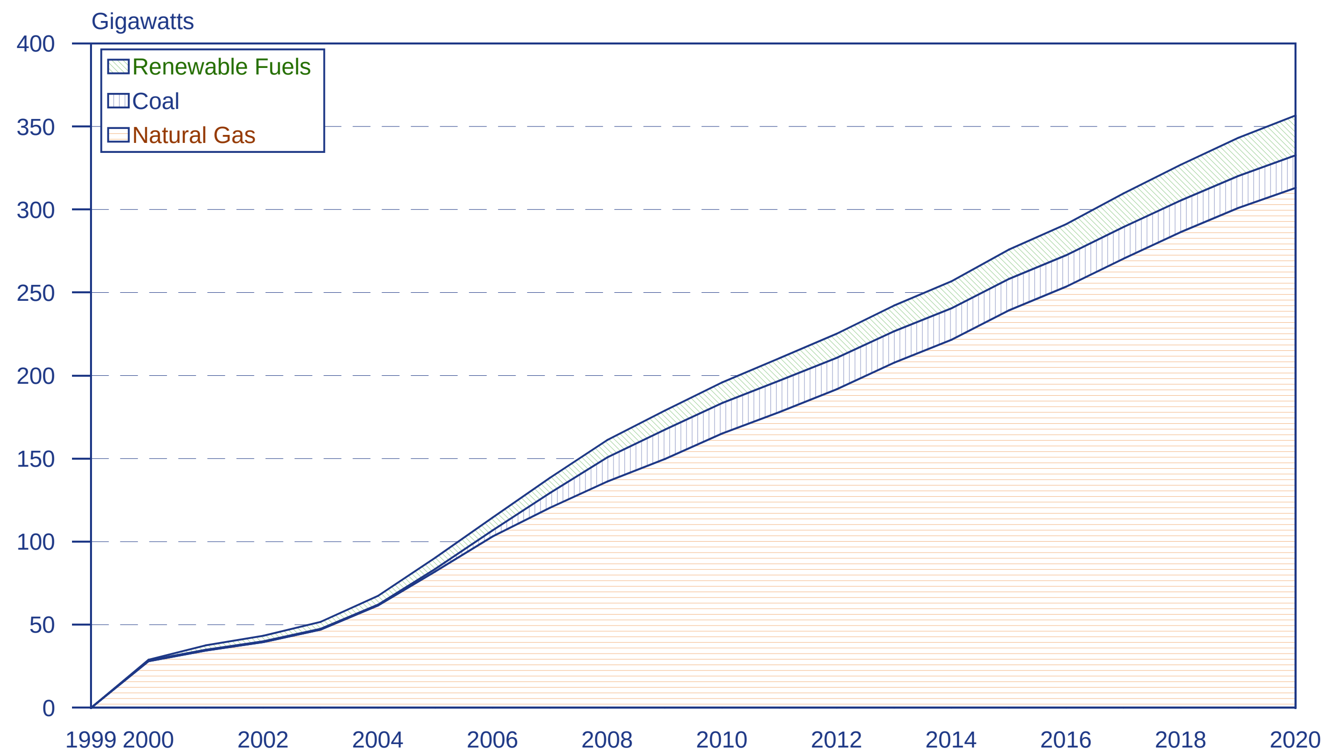
Over the next 20 years the demand for electricity is projected to grow by 1.8 percent per year, as compared with the 1990s, during which electricity consumption grew by 2.3 percent annually. Growth in electricity use is expected to slow as new, more efficient appliances enter the market and industrial production continues to shift away from energy-intensive industries. With 3.0-percent annual growth projected for the economy as a whole, the overall electric intensity of the U.S. economy—measured as the ratio of electricity use to gross domestic product—is projected to decline by 22 percent between 2000 and 2020.

To meet the growth in demand for electricity, 357 gigawatts of new generating capacity is projected to be needed (Figure 4). The vast majority of new plants are expected to be natural gas fired, with lesser amounts of new coal-fired and renewable capacity. New natural gas-fired combustion turbines and combined cycle plants are the most economical options for most uses. They generally have lower capital costs than other options and they are becoming increasingly efficient.

With the addition of many new natural-gas-fired plants, the share of electricity generated from natural gas is projected to grow from 16 percent in 1999 to 34 percent in 2020 (Figure 5). Generation from coal-fired plants is also projected to grow as a small number of new plants are added and as existing plants are used more intensively, but the *share* of generation coming from coal is projected to decline slightly. On the other hand, generation from oil and from nuclear power is expected to decline as some older plants are retired in the later years of the forecast. Generation from renewable plants is projected to increase, but not enough to maintain its current share.

Although fossil fuel use is expected to grow over the next 20 years, SO_2 and NO_x emissions are not projected to be higher in 2020 than they are today (Figures 6 and 7). As a result of the emission reduction programs established in the Clean Air Act Amendments of 1990 (CAAA90) SO_2 and NO_x emissions are expected to be

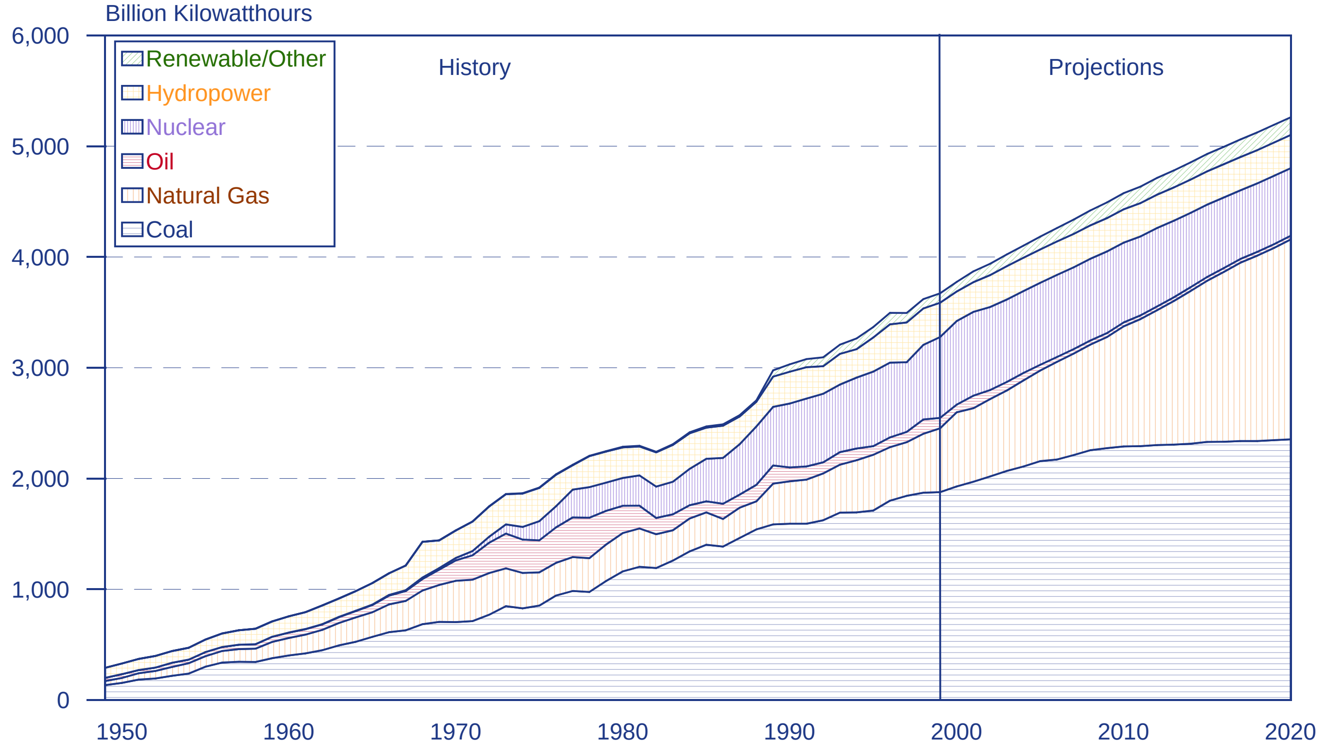
Figure 4. Projected Cumulative Additions to U.S. Electricity Generating Capacity, 1999-2020



Source: National Energy Modeling System, run SCENABS.D080301A.

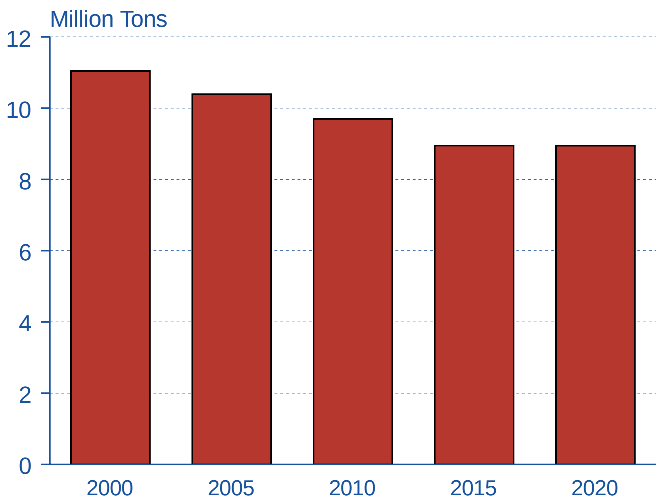
lower in 2020 than they were in 1999. For example, the CAAA90 cap on power sector SO_2 emissions is set at 8.95 million tons for the years 2010 and beyond, and that cap is expected to become binding in the later years of the reference case projections as power companies exhaust their supplies of banked allowances.[10] For NO_x, 19 States in the Midwest and Eastern regions and the District of Columbia are projected to see significant reductions in emissions beginning in 2004, when a summertime emissions cap takes effect. The summer

Figure 5. Electricity Generation by Fuel, 1949-1999, and Projections for the Reference Case, 2000-2020



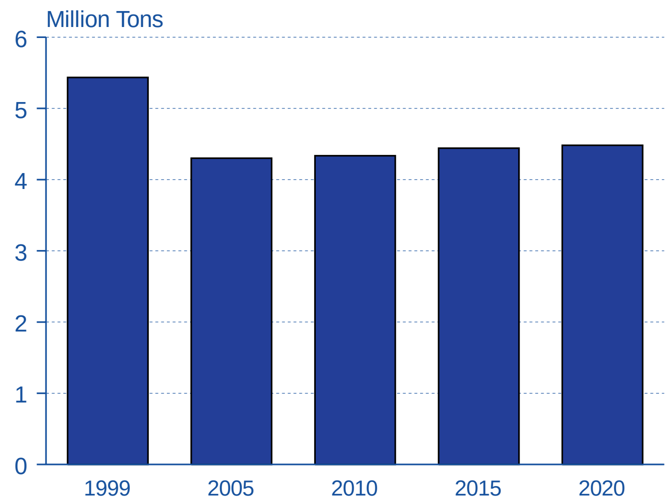
Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run SCENABS.D080301A.

Figure 6. Projected Electricity Generation Sector Sulfur Dioxide Emissions in the Reference Case, 2000-2020



Source: National Energy Modeling System, run SCENABS. D080301A.

Figure 7. Projected Electricity Generation Sector Nitrogen Oxides Emissions in the Reference Case, 2000-2020



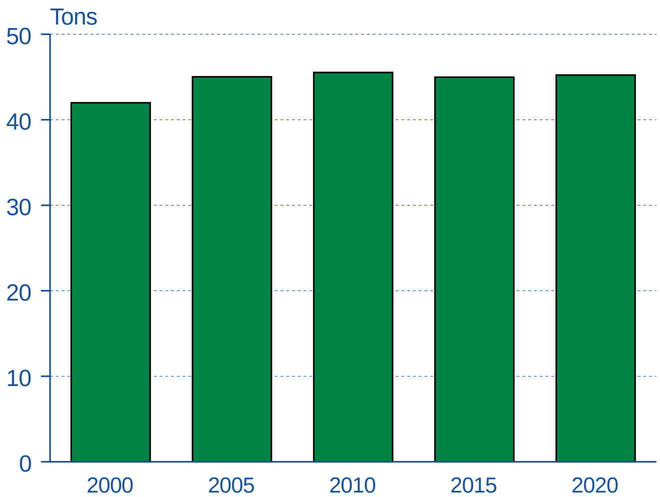
Source: National Energy Modeling System, run SCENABS. D080301A.

[10] Power companies created "banked allowances" by overcomplying during the first phase of the CAAA90 SO_2 program, from 1995 to 1999. They can use those allowances in later years.

season cap begins in 2004 and is maintained throughout the rest of the projections. Total U.S. NO_x emissions are projected to increase slightly after 2004, but not enough to offset the earlier reduction.

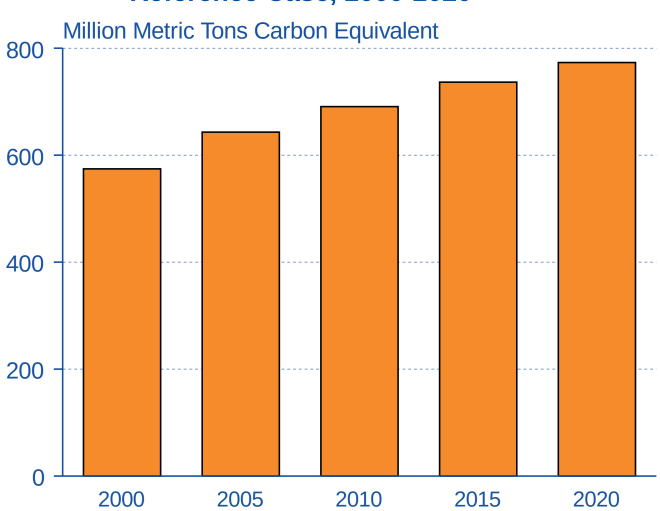
Hg emissions from electric power plants are projected to remain fairly steady between 2000 and 2020—hovering around 45 tons from 2005—despite the expected increase in coal use (Figure 8). Some existing coal plants are projected to add scrubbers to reduce SO_2 emissions and selective catalytic reduction (SCR) equipment to reduce NO_x emissions, and all new coal plants are projected to have scrubbers, SCRs, and fabric filters. While these technologies are designed primarily to reduce SO_2, NO_x, and particulate emissions, they also help to reduce Hg emissions. The addition of this equipment is expected to nearly offset the increase in Hg emissions that would be expected with increasing coal use.

Figure 8. Projected Electricity Generation Sector Mercury Emissions in the Reference Case, 2000-2020



Source: National Energy Modeling System, run SCENABS. D080301A.

Figure 9. Projected Electricity Generation Sector Carbon Dioxide Emissions in the Reference Case, 2000-2020



Note: Does not include CO_2 emissions from cogenerators.
Source: National Energy Modeling System, run SCENABS. D080301A.

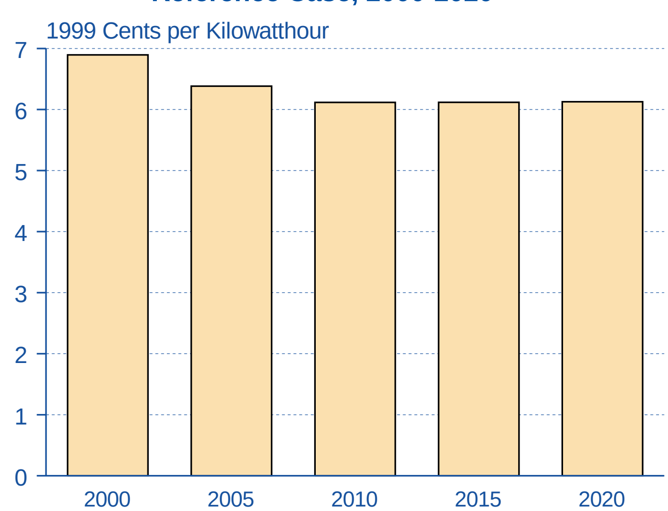
Unlike NO_x, SO_2, and Hg emissions, CO_2 emissions (expressed in metric tons carbon equivalent throughout this report) are projected to rise steadily over the next 20 years as the power sector becomes increasingly dependent on fossil fuels (Figure 9). Between 1999 and 2020, the share of electricity generation from fossil fuels is expected to increase from 69 percent to 80 percent, and CO_2 emissions from electric power plants are expected to increase by 217 million metric tons—39 percent—over the next 20 years. The actions projected to be taken to reduce SO_2 and NO_x emissions in the reference case in response to the CAAA90 are not expected to reduce power sector CO_2 emissions, because they will not lead to significant fuel switching.

Despite the growing demand for electricity, prices are expected to decline by 9 percent in real terms over the next 20 years (Figure 10). The phase-in of competition in many regions of the country is one factor in the expected decline, in addition to falling coal prices and the declining cost and increasing performance of new natural gas technologies.

Reducing Electricity Sector NO_x, SO_2, and Hg Emissions

A number of options are available to reduce power sector emissions of NO_x, SO_2, and Hg. They include emission control options such as adding combustion controls and SCR and selective noncatalytic reduction (SNCR)

Figure 10. Projected Electricity Prices in the Reference Case, 2000-2020



Source: National Energy Modeling System, run SCENABS. D080301A.

equipment designed primarily to reduce NO_x emissions, flue gas desulfurization equipment (scrubbers) to reduce SO_2, and activated carbon injection (ACI) equipment to reduce Hg.[11] Other options for reducing NO_x, SO_2, and Hg emissions include fuel switching (either by changing fuels at existing plants or by retiring plants and replacing them with plants that use different fuels) and reducing consumer demand.

In the cases examined in this report all three of the options above are expected to play a role; but by a large margin, the key strategy projected to be used is the installation of emissions control equipment to reduce the three emissions. As shown in Table 3, the amount of equipment projected to be added increases as the emission caps on the three pollutants are tightened. For example, scrubbers are projected to be added to 90 gigawatts of capacity by 2020 in the 50-Percent Reduction case and to 151 gigawatts in the 75-Percent Reduction case. The values in Table 3 indicate that emissions control equipment is expected to be added to many of the existing U.S. coal-fired electric power plants, which currently total just over 300 gigawatts of capacity. The percentage of existing coal-fired capacity expected to have SO_2 scrubbers is larger than suggested by the values shown in Table 3, because 90 gigawatts of that capacity already is equipped with scrubbers.

The projections are similar for NO_x emission controls: SCRs are expected to be added to 98 gigawatts of capacity in the 50-Percent Reduction case and to 218 gigawatts in the 75-Percent Reduction case. The investment in SCR technology increases continuously across the cases as the required percentage reduction increases. The same is true for expected additions of SNCRs between the 50-Percent and 65-Percent Reduction cases; but when the required reduction is raised to 75 percent, power suppliers are projected to shift increasingly to SCR technology because it can achieve greater NO_x reduction.

Relative to the reference case, less capacity is expected to be retrofitted with NO_x control technology in the 50-Percent Reduction case, because the 19-State summer season NO_x cap and trade program that is scheduled to begin in 2004 in the reference case is replaced by the national cap and trade program in each of the analysis cases. In the 50-Percent Reduction case the annual NO_x cap, 3.1 million tons (roughly equivalent to an average annual emission rate of 0.25 pounds per million Btu of fossil fuel consumed in 2010 and 0.18 pounds per million Btu in 2020), can be met with less control equipment than is required to meet the seasonal cap in the reference case. The 19-State summer season NO_x emissions cap represented in the reference is based on a target average emission rate of 0.15 pounds per million Btu of fossil fuel consumed. The NO_x emission caps in the 65-Percent and 75-Percent Reduction cases—2.2 million tons and 1.5 million tons, respectively—lead to average annual NO_x emission rates below 0.15 pounds per million Btu by 2020.

In many other aspects—including fuel use, generation by fuel, and capacity additions by type—the results in the three analysis cases are similar to those in the reference case. As the emission caps are tightened across the cases there is a slight shift from coal-fired generation to

Table 3. Projected Additions of Emissions Control Equipment, 1999-2010 and 1999-2020
(Gigawatts)

Analysis Case	Cumulative Capacity Adding Controls				
	SO_2 Scrubber	Selective Catalytic Reduction (SCR)	Selective Noncatalytic Reduction (SNCR)	Hg Fabric Filter	Hg Spray Cooler
1999-2010					
Reference	8.9	90.9	28.5	0.0	0.0
50-Percent Reduction	47.8	46.6	2.7	45.5	0.0
65-Percent Reduction	42.9	93.8	15.2	60.5	0.3
75-Percent Reduction	61.7	141.7	10.3	57.7	11.9
1999-2020					
Reference	17.5	91.1	46.0	0.0	0.0
50-Percent Reduction	90.0	98.0	14.6	45.5	1.6
65-Percent Reduction	127.3	156.3	55.5	60.5	3.8
75-Percent Reduction	151.5	218.1	43.8	66.9	29.3

Note: The reference case assumes a 19-State summer season NO_x program beginning in 2004. The analysis cases assume the proposed annual programs without the summer limits. SCRs and SNCRs are NO_x removal technologies.

Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512.D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

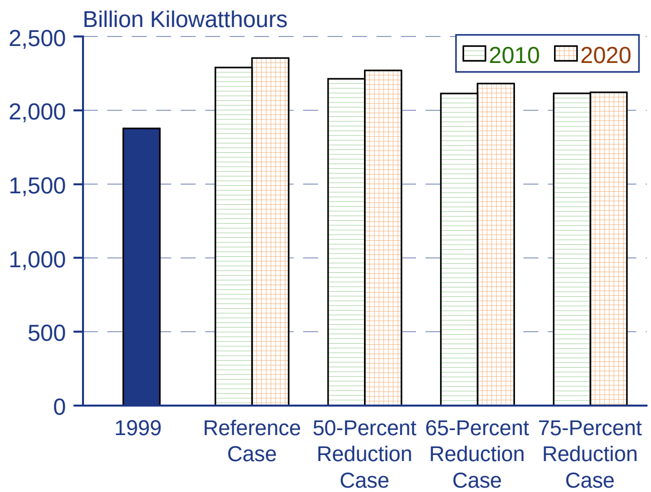
[11]Substantial uncertainty remains about the measurement and control of Hg emissions. For a discussion of this issue see pages 16 and 17 in Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/.

natural-gas-fired generation (Figures 11 and 12). For example, in the 75-Percent Reduction case, which is projected to have the largest shift, natural-gas-fired generation in 2020 is expected to be 10 percent above and coal-fired generation 10 percent below the reference case levels. The shifts in the two other cases are smaller.

As the emission caps are tightened across the cases, the projected allowance prices for NO_x, SO_2, and Hg are expected to increase, particularly as the caps are lowered to the limits in the 75-Percent Reduction case (Table 4). In this case, the emissions controls must be added to units for which the marginal costs per unit of reduction are higher. This is particularly true for allowance prices for NO_x and Hg. For example, the annual NO_x allowance price[12] in 2020 in the 65-Percent Reduction case is projected to be $1,457 per ton, but in the 75-Percent Reduction case it is 94 percent higher, at $2,825 per ton. Similarly, the Hg allowance price in 2020 in the 65-Percent Reduction case is projected to be $41,190 per pound, but in the 75-Percent Reduction case it is more than twice as high, at $85,225 per pound.[13] The requirements to reduce Hg have a significant impact on the SO_2 allowance price, especially as the Hg emission caps are initially phased in. The SO_2 allowance price in the 75-Percent Reduction case in 2010 is lower than in the 65-Percent Reduction case, because efforts to meet the tighter Hg emissions limit in the 75-Percent case also reduce SO_2 emissions.

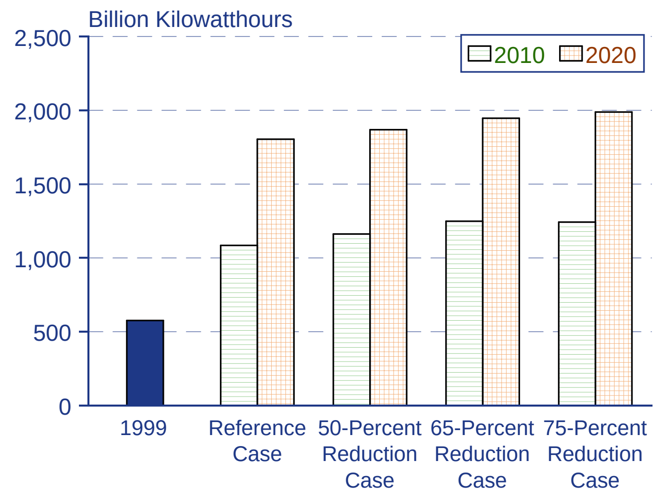
The increasing cost of allowances across the cases is driven by several factors. For example, for a particular plant, the plant size, sulfur content of the coal used, and plant capacity factor are important in determining the cost of reducing SO_2. Smaller plants are in general more costly (per unit of capacity) to retrofit with scrubbers than are larger plants. It is also more expensive on a per ton removal basis to control SO_2 at a plant using relatively low-sulfur coal. Similarly, it is more expensive on a per ton removal basis to add a scrubber to a plant that is not used intensively. For example, for a large plant with scrubber capital costs of $200 per kilowatt, using a 2-percent sulfur coal and operating at a 75-percent capacity factor, the cost of removing SO_2 is expected to be approximately $250 per ton. If the plant used a 1-percent sulfur coal the cost estimate would double, and if it operated at a 37.5-percent capacity factor the cost estimate would double again. For a smaller plant, with scrubber capital costs that could be $400 per kilowatt or more, the corresponding SO_2 removal costs would be even higher. As a result, when controls must be added to smaller plants that are already using relatively low-sulfur coals and operating less intensively, the per ton costs of removal can be quite high.[14]

Figure 11. Projected Electricity Generation from Coal-Fired Power Plants in Four Cases, 2010 and 2020



Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

Figure 12. Projected Electricity Generation from Natural-Gas-Fired Power Plants in Four Cases, 2010 and 2020



Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

[12]The reference case includes the summer season NOx cap that begins in 2004 for 19 midwestern and eastern states and the District of Columbia. The analysis cases include only the annual NO_x reduction programs requested.

[13]The Hg allowance price in 2010 is $0 in each of the three analysis cases, because it is assumed that each plant must achieve a specified reduction—set to achieve half the total required reduction—by 2007. Because these reductions are sufficient to meet the 2010 overall cap, the allowance price is $0.

[14]The examples given in this paragraph assume a 15-percent fixed charge factor, a 2.5-percent heat rate penalty, and a coal price of $1 per million Btu. They do not represent the costs for any particular plant but are meant to be illustrative.

Investments in emissions control technology, combined with higher expenditures for natural gas, are projected to lead to higher supplier resource costs in the three emission reduction cases (Table 5). Supplier resource costs include electricity producers' expenditures on fuel, nonfuel operations and maintenance costs, and investments in new plants and emissions control equipment. In the 75-Percent Reduction case, suppliers are projected to incur $89 billion (constant 1999 dollars) more in resource costs between 2001 and 2020 than in the reference case (Figure 13). On an average annual basis, the increases in resource costs in the three cases average $1.4 billion, $3.3 billion, and $4.4 billion, in the 50-Percent, 65-Percent, and 75-Percent Reduction cases, respectively.[15]

Changes in electricity prices are expected to parallel the changes in supplier resource costs in the three analysis cases (Figure 14). In percentage terms, electricity prices in 2010 are expected to range between 0 and 2 percent higher than in the reference case; and in 2020, as the emission caps tighten, they are expected to range between 2 and 6 percent higher. On an average annual basis, the projected increases in electricity revenues (prices times sales) relative to the reference case in 2020 are $4 billion, $9 billion, and $14 billion in the 50-Percent, 65-Percent, and 75-Percent Reduction cases, respectively.

Offsetting CO_2 Emissions Growth After 2008

Because of the slight shift from coal-fired to natural-gas-fired generation, reducing power sector NO_x, SO_2, and Hg emissions is projected to have some impact on CO_2 emissions (Figure 15). In 2010, CO_2 emissions in the analysis cases are projected to be between 14 million and 33 million metric tons below the level expected in the reference case. (The projections for CO_2 emissions are lower in the more stringent cases, because the expected shifts from coal to natural gas are larger.) In 2020, the range is slightly wider, between 12 million and 36 million metric tons. Even with these reductions, however, power sector CO_2 emissions in 2020 are projected to be between 262 million and 286 million metric tons (between 55 and 60 percent) above the 1990 level.

The potential exists for an increase in the use of coal and in its associated emissions in sectors of the economy (i.e., residential, commercial, and industrial) not covered by emission cap programs. However, because coal plays

Table 4. Key Projections in the Analysis Cases, 2010 and 2020

Projection	Reference Case	50-Percent Reduction Case	65-Percent Reduction Case	75-Percent Reduction Case
2010				
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.82	2.85	2.95	2.98
SO_2 Allowance Price (1999 Dollars per Ton)	180	210	415	296
NO_x Allowance Price: Annual (1999 Dollars per Ton)	0	1,208	1,491	2,072
NO_x Allowance Price: Seasonal (1999 Dollars per Ton)	4,404	0	0	0
Hg Allowance Price (1999 Dollars per Pound)	0	14,452	20,124	31,923
Electricity Price (1999 Cents per Kilowatthour)	6.12	6.12	6.23	6.23
Electricity Sales (Billion Kilowatthours)	4,133	4,135	4,122	4,120
Electricity Industry Revenues (Billion 1999 Dollars)	253	253	257	257
2020				
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	3.10	3.19	3.35	3.41
SO_2 Allowance Price (1999 Dollars per Ton)	200	719	1,390	1,737
NO_x Allowance Price: Annual (1999 Dollars per Ton)	0	1,108	1,457	2,825
NO_x Allowance Price: Seasonal (1999 Dollars per Ton)	5,087	0	0	0
Hg Allowance Price (1999 Dollars per Pound)	0	21,119	41,190	85,225
Electricity Price (1999 Cents per Kilowatthour)	6.13	6.22	6.35	6.48
Electricity Sales (Billion Kilowatthours)	4,763	4,749	4,736	4,716
Electricity Industry Revenues (Billion 1999 Dollars)	292	295	301	305

Note: The reference case assumes a 19-State summer season NO_x program beginning in 2004. The analysis cases assume the proposed annual programs without the summer limits.

Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512.D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

[15]The changes in resource costs reported here do not include the financing and profits typically associated with new investments. If the changes in capital investments are put in the form of annuities, the changes in resource costs are $3.1 billion, $5.7 billion, and $7.2 billion in 2010 in the 50-, 65-, and 75-Percent cases, respectively. In 2020 the corresponding values are $4.8 billion, $9.1 billion, and $12.3 billion.

such a small role in those sectors and the projected decreases in coal prices are generally expected to be less than a few percent, the potential for emission "leakage" appears slight.[16] The increase in natural gas prices that is projected to occur because of increased use in the electricity sector appears to be more significant, leading to lower overall fuel consumption and lower emissions in the non-electricity sectors.

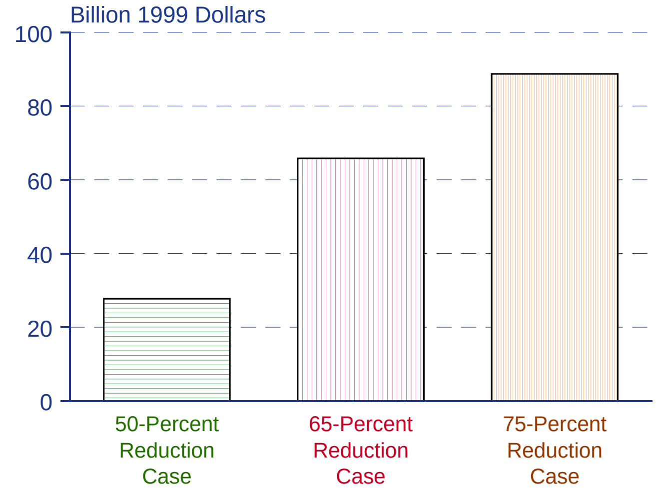
If a cap is imposed on power sector CO_2 emissions at the projected 2008 reference case level of 672 million metric tons (197 million metric tons or 41 percent above the 1990 level), power suppliers will have to either take action to reduce their emissions or purchase offsets for between 65 million and 89 million metric tons by 2020 (Figure 16). (Again, fewer offsets are required in the more stringent cases, because the expected shifts from coal to natural gas as a result of the other emission caps are larger.) Note that no offsets are required until projected CO_2 emissions in each of the three analysis cases exceed the assumed CO_2 cap (the 2008 level expected in the reference case), which is projected to occur in 2010 in the 50-Percent Reduction case, in 2012 in the 65-Percent Reduction case, and in 2013 in the 75-Percent Reduction case.

To determine the prices that U.S. power suppliers might be willing to pay for offsets, the three analysis cases were rerun with CO_2 emissions capped at the 2008 reference case level (Figure 17). The projected allowance prices in 2020 range between $33 and $54 per metric ton. As compared with earlier studies of the expected costs to the U.S. power sector of meeting the Kyoto Protocol requirements, these allowances prices are quite low; however, the CO_2 emissions cap assumed in this analysis (41 percent above the 1990 level) is very different from the U.S. target specified in the Kyoto agreement (7 percent below the 1990 level). The key CO_2 compliance strategy in these cases is expected to be a further shift from coal to natural-gas-fired generation. For example, in the 75-Percent Reduction case with no CO_2 cap, coal-fired generation in 2020 is projected to be 10 percent below the reference case level, and natural-gas-fired generation is projected to be 10 percent above the reference case level.

In the 75-Percent Reduction case with a CO_2 cap set to the 2008 reference case level, the impacts are approximately doubled.

Because of the reduced reliance on coal projected in the cases with CO_2 caps, the investments in NO_x, SO_2, and Hg control equipment are projected to be lower. For example, scrubbers are projected to be added to nearly 152 gigawatts of capacity in the 75-Percent Reduction case without a CO_2 cap, as compared with only 115 gigawatts when the CO_2 cap is incorporated. In the early years of the projections, the expected investments in control equipment to reduce emissions of NO_x, SO_2, and Hg in the cases with and without CO_2 caps are similar; but they are much lower in the later years, when CO_2 emission caps are imposed. The projected allowance prices for NO_x and Hg are also lower when the CO_2 emissions cap is included.

Figure 13. Electricity Supplier Resource Costs: Projected Changes from the Reference Case in the Three Analysis Cases, 2001-2020



Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

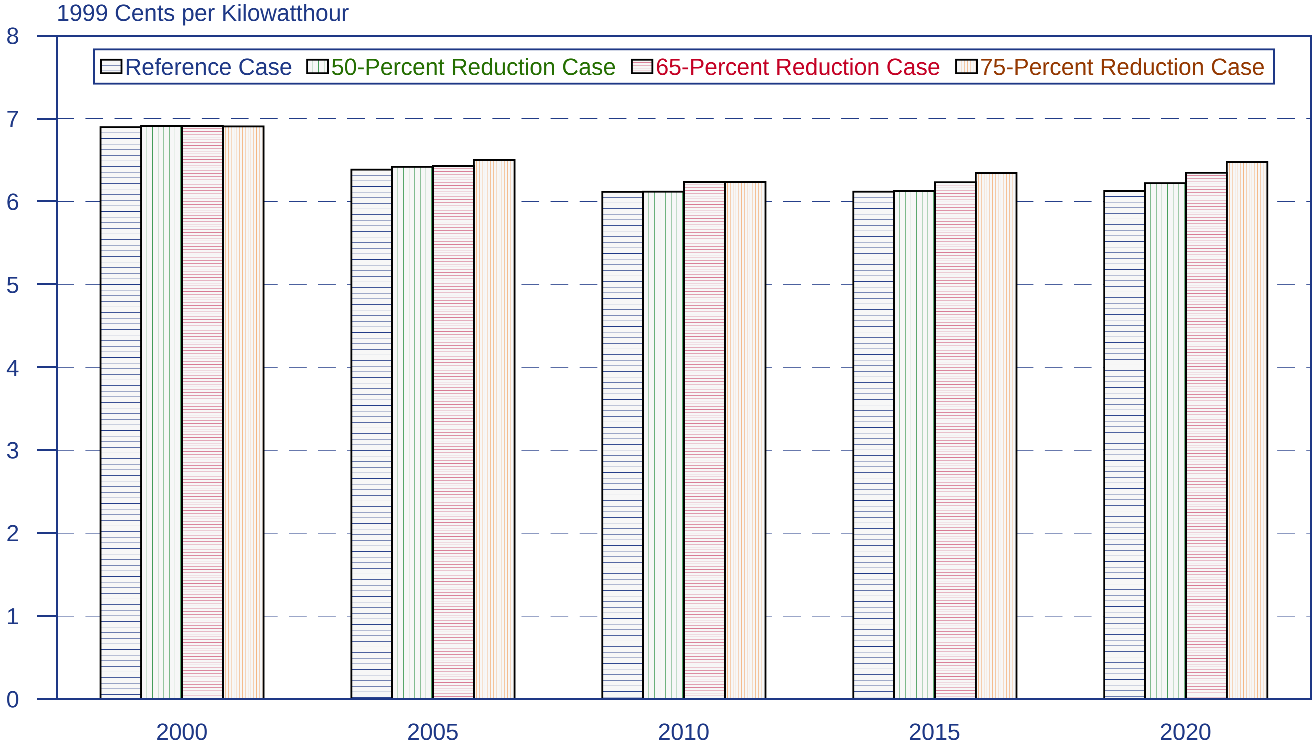
Table 5. Electricity Supplier Resource Costs: Projected Changes from the Reference Case in the Three Analysis Cases, 2001-2020

Analysis Case	Total Change (Billion 1999 Dollars)	Average Annual Change (Billion 1999 Dollars)	Total Change per Kilowatthour Generated (Percent)
50-Percent Reduction	28	1.4	1.5
65-Percent Reduction	66	3.3	3.5
75-Percent Reduction	89	4.4	4.8

Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

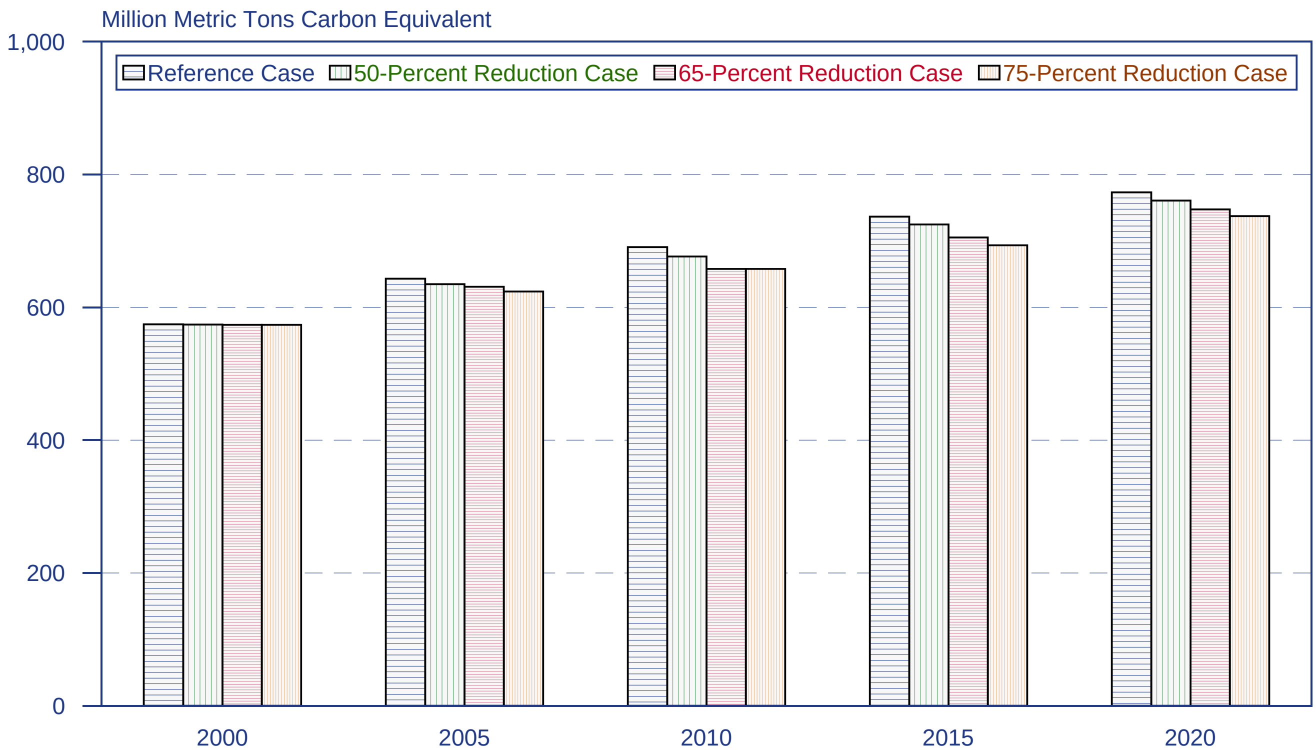
[16]Emission leakage occurs when control programs in a covered sector lead to actions that increase emissions in sectors not covered by the programs.

Figure 14. Projected Electricity Prices in Four Cases, 2000-2020



Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

Figure 15. Projected Electricity Generation Sector Carbon Dioxide Emissions in Four Cases, 2000-2020



Note: Does not include CO_2 emissions from cogenerators.

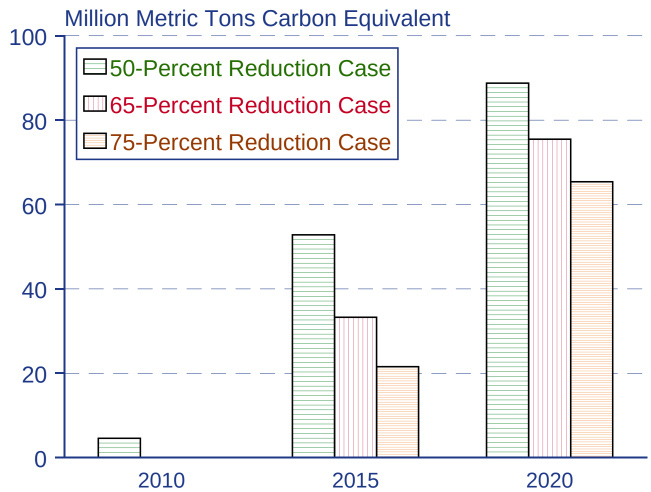
Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

The projected CO_2 allowance prices in the cases with CO_2 caps represent the marginal cost of compliance within the U.S. power sector. They also represent the maximum price that power suppliers would be willing to pay for offsets. They would incur these costs only if they could not purchase offsets at a lower price. The price that U.S. power suppliers might have to pay to offset increases in CO_2 emissions above the 2008 reference case level is difficult to determine, because it would depend on what the rest of the world did in response to any greenhouse gas emissions reduction agreement. It would also depend on how offset programs were defined, implemented, and verified.

The National Energy Modeling System does not represent energy or non-energy markets outside the United States, and EIA has not made an independent assessment of how world offset markets might evolve. Figure 18 shows world energy sector CO_2 abatement supply curves (the upward sloping curves) produced by the Pacific Northwest Laboratory's Second Generation Model (SGM), matched against the projected requirement for reductions if all countries complied with the Kyoto Protocol (the vertical lines).[17]

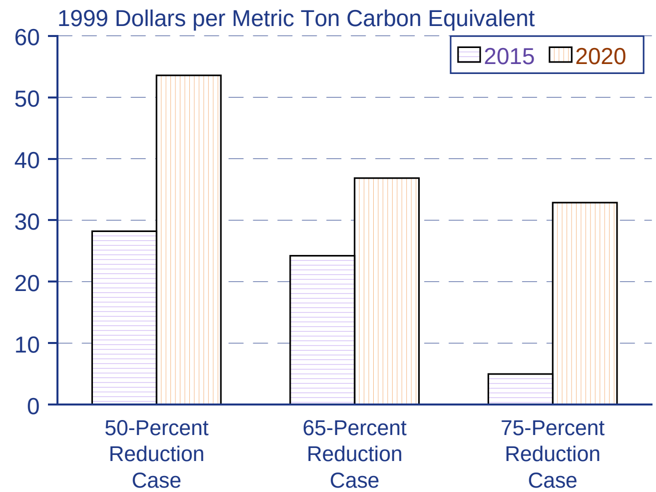
The supply curves in Figure 18 represent the projected CO_2 emission reductions (abatement) from reference case projections that would occur in the energy sectors of all countries in response to rising prices for carbon allowances. Because worldwide trading is assumed, all countries—including those without greenhouse gas reduction targets in the Kyoto Protocol—are included in the supply curves, assuming full compliance with the Kyoto Protocol. Countries with greenhouse gas reduction targets can trade with other countries by using the Protocol's clean development mechanism or joint implementation provisions. For example, if an Annex I country made investments that led to lower greenhouse gas emissions in China, the reductions would be counted toward the investing country's reduction target. The estimates include offsets created in each country's energy sector but exclude offsets that might be available from non-energy activities, such as changes in agricultural practices and reforestation activities. The reductions would be expected to come from numerous sources, including changes in fuel use, improvements in production efficiency (more efficient power plants), and reductions in consumer energy use.

Figure 16. Projected Carbon Offsets Required To Cap Power Sector Carbon Dioxide Emissions at the 2008 Reference Case Level in the Three Analysis Cases, 2010, 2015, and 2020



Note: Does not include CO_2 emissions from cogenerators.
Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

Figure 17. Projected Carbon Offset Prices with Power Sector Carbon Dioxide Emissions Capped at the 2008 Reference Case Level in the Three Analysis Cases, 2015 and 2020



Note: Does not include CO_2 emissions from cogenerators.
Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

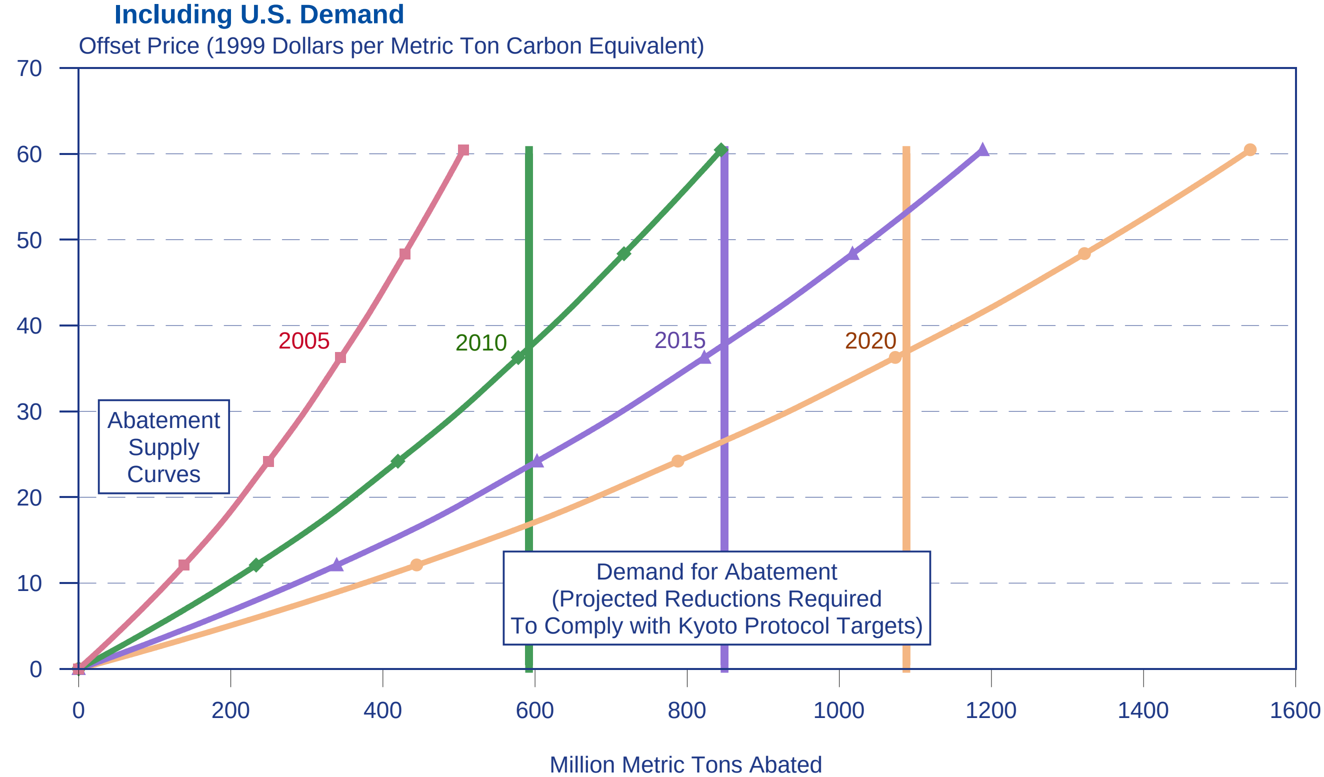
[17]The SGM supply and demand curves were modified to be consistent with the Energy Information Administration's *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001). Essentially the percentage change in carbon emissions reflected in the SGM curves at different allowance prices was applied to the International Energy Outlook emissions projections for various parts of the world to develop revised abatement demand and supply curves. For more information on the SGM model, see J.A. Edmonds, H.M. Pitcher, D. Barns, R. Baron, and M.A. Wise, "Modeling Future Greenhouse Gas Emissions: The Second Generation Model Description," in *Modeling Global Change*, L.R. Klein and Fu-chen Lo, eds (New York, NY: United Nations University Press, 1993).

The demand curves represent the estimated reduction in carbon emissions required by Annex I countries to reach full compliance with the Kyoto Protocol. The United States is included in both the supply and demand curves in Figure 18, assuming full U.S. compliance with the Protocol. The intersections of the lines of the same color represent the prices at which the market for energy sector offsets would clear in 2010, 2015, and 2020. Both the supply of offsets and the demand for them are projected to grow over time as a result of expected economic growth and changing technologies.

Because this study does not assume U.S. participation in the Kyoto Protocol, adjustments were made to remove the U.S. contribution from the demand curves in Figure 18. Without U.S. participation in the Protocol, the demand for offsets would be much lower than depicted in Figure 18. For example, if the rest of the world complied with the Protocol while the United States did not, the world trading price for energy sector carbon allowances would be fairly low—rising from just a few dollars in 2010 to roughly $5 in 2015 and $8 in 2020 (Figure 19). The supply curves in Figure 19 are the same as those in Figure 18, but the demand curves have been shifted to the left (lowered), because the U.S. carbon reduction requirement has been removed. The price would rise slightly as U.S. power suppliers entered the market to purchase the 65 to 89 million metric tons of offsets they would need; however, assuming a price of roughly $10 per metric ton in 2020, the total cost of offsets for U.S. power suppliers would be between $654 million and $888 million in the three analysis cases.

The net result of the these estimates is that if power suppliers are required to purchase offsets for any CO_2 emissions above the level projected to be emitted in 2008 in the reference case, their costs in 2020 could rise by as little as $654 million or by as much as $888 million. The range in cost estimates results from the differences in offsets required in the three cases (between 65 million and 89 million metric tons carbon equivalent in 2020). The prices and costs could be lower if offsets from other greenhouse gases or carbon sinks were available. The analysis above is predicated on the assumption that the regional abatement costs curves provided by the SGM model are rreasonable estimates. Because we have no way to verify their reasonableness, that assumption increases the uncertainty of the cost estimates.

Figure 18. Worldwide Energy Sector Carbon Abatement Supply and Demand Curves, Including U.S. Demand



Note: The intersections of the lines of the same color represent the prices at which the market for energy sector offsets would clear in 2010, 2015, and 2020.

Source: Pacific Northwest Laboratory, Second Generation Model output (August 30, 2001).

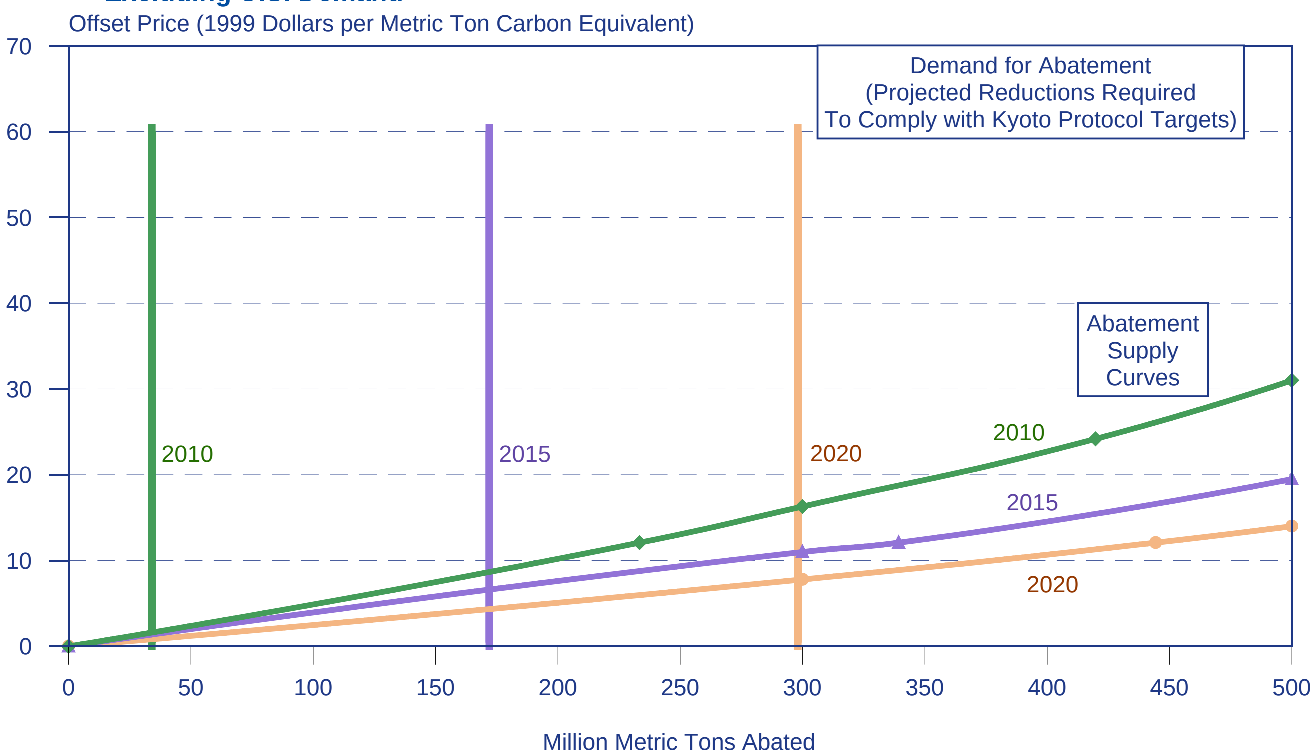
Uncertainties

As with any 20-year projections, there is considerable uncertainty about the results of this analysis. The potential role of new generating and emissions control technologies, future fuel prices, the possibility of market reliability problems as the emission reduction programs are phased in, the types of emission reduction programs established, and the impact on evolving electricity markets are especially uncertain. The evolution of new technologies is particularly unpredictable, and Hg emissions control technologies are relatively new and untested on a commercial scale. In addition, while a substantial amount of data about Hg emissions from coal-fired power plants has been collected in recent years, there still is considerable uncertainty in the measurement of Hg emissions and the extent to which control technologies designed primarily to remove NO_x or SO_2 might contribute to reducing Hg. It is possible that new, innovative technologies could be developed that would lower the costs of Hg removal, but it is also possible that reducing Hg substantially at some facilities may be more difficult than is presently expected with the limited data available. The emission caps studied in this analysis would likely stimulate additional research and development efforts for Hg control technologies.

An earlier EIA analysis examined several sensitivity cases, including ones with alternative emission caps, alternative technology assumptions, and alternative fuel price assumptions. The "high technology" Hg removal case suggested that if Hg control technologies improved significantly, the total and marginal costs of reducing Hg emissions could be much lower than shown here.[18]

One key uncertainty is the future price of natural gas. The vast majority of the new electricity generating capacity projected to be added over the next 20 years—more than 90 percent—is expected to be natural gas fired, producing relatively low NO_x emissions and virtually no SO_2 or Hg emissions. As a result, their addition and utilization would not create substantial upward pressure on emission allowance markets. If, however, natural gas prices turn out to be higher than projected, new coal-fired plants could become economically attractive, and their higher emission rates could increase the cost of meeting the emission caps and lead to higher electricity prices.

Figure 19. Worldwide Energy Sector Carbon Abatement Supply and Demand Curves, Excluding U.S. Demand



The intersections of the lines of the same color represent the prices at which the market for energy sector offsets would clear in 2010, 2015, and 2020.

Source: Pacific Northwest Laboratory, Second Generation Model output (August 30, 2001).

[18]For discussion of an enhanced Hg control technology case and other emission cap sensitivity cases, see Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR / OIAF / 2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov / oiaf / servicerpt / epp / .

Because of the amount of emissions control equipment projected to be added, careful planning would be needed in all cases to ensure that the reliability of the electricity system would not be compromised during the transition period. System reliability could be of particular concern during the period when a large amount of emissions control equipment would have to be added. In many cases plants must be taken out of service when the final connections are made for new emissions control equipment. If extended outages resulted, or if power suppliers did not coordinate their outages to ensure that a large number of facilities would not be out of service at the same time, system interruptions could create the potential for price volatility in power markets.

There is also considerable uncertainty about the price of emission allowances that might evolve. There are numerous policy instruments—such as technical standards, taxes, free allowance cap and trade programs, auction-based cap and trade programs, and updating output-based allowance cap and trade programs—that could be used. The instrument chosen will affect the market response. In addition, because the different emission allowance markets are intertwined—actions taken to reduce one pollutant will impact the others—the design of each program will affect the others. Therefore, allowance prices could be very sensitive to program design issues. For CO_2 emissions, the potential price of offsets in world markets is very uncertain. Their price and availability will depend on the projected overall economic and energy market conditions in numerous countries over the next 20 years. In addition, the rules on what types of programs might be included in any trading program have yet to be finalized. This analysis only considered offsetting carbon emissions in world energy markets.

Finally, wholesale and retail electricity markets in the United States currently are undergoing significant change, moving from a long period of average cost regulated prices to a system in which power prices are set by market forces. The exact form that each of the regional markets will take is not known at this time. Changes in market structure as a result of the transition to competition could affect the choice of policy instruments needed to promote the efficient implementation of new emissions standards and the response by consumers to them. As mentioned above, a number of policy instruments are available. Each of the options would have different price and cost impacts. This study assumes that wholesale generation markets will behave competitively, and that any compliance costs that increase the operating costs of facilities setting the market price for power will be passed on to consumers. If the markets do not behave competitively, the cost and price changes could be different from those projected in this analysis.